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**BEFORE THE PUBIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Policies, Procedure and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	Rulemaking 14-08-013 (Filed August 14, 2014)

COMMENTS OF SOLARCITY CORPORATION ON THE ORDER INSTITUTING RULEMAKING

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In accordance with the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, SolarCity submits these comments in response to the questions posed in the August 14, 2014 Order Instituting Rulemaking ("OIR") regarding policies, procedures and rules to guide California investor-owned electric utilities (IOUs) in developing their Distribution Resources Plan Proposals.

I. DESCRIPTION OF SOLARCITY

SolarCity is California's leading full service solar power provider for homeowners and businesses – a single source for engineering, design, financing, installation, monitoring, and support. The company provides cost-effective financing that enables customers to eliminate the high upfront costs of deploying solar. SolarCity has more than 3,000 California employees, based at 32 facilities around the state and has provided clean energy services to more than 50,000 California customers.

II. COMMENTS ON QUESTIONS POSED IN OIR

1. What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

SolarCity strongly supports the development and utilization of Distribution Resource Plans in compliance with AB 327. The development of DRPs offers an important opportunity to add transparency to the "black box" of utility resource distribution planning and establish a more effective approach that ensures the utilities recognize and consider distributed energy resources as they plan for and make investments in the distribution system. As distributed technologies grow more sophisticated and widespread, alternatives to the conventional "wires solutions" are becoming increasingly viable. Additionally, the deployment of DERs and the ability to fully take advantage of them will require changes in the capabilities of the distribution system and its operation. SolarCity offers responses to questions below on the specific criteria that should guide the development of DRPs, and looks forward to actively participating in the development of the DRPs.

2. What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

AB 327 established a number of statutory requirements that must be met in order for the plans developed by the utilities to be deemed compliant. Each of these requirements provides a set of issue areas that plans will need to fully address. First and foremost, there must be a robust assessment of the costs and benefits yielded by distributed resources across the utilities' respective distribution systems. The utilities will need to include in their distribution plans a proposed methodology that effectively assesses the value DERs provide in the near and longer term, and identify how this value, including the various categories of costs and benefits identified in the statute, changes depending on where these resources are located on the system. As observed in the Report attached to the OIR, identifying trade-offs between various objectives is a critical element of this exercise. This task is no trivial endeavor given the variety of technologies available and number of scenarios one could run to assess costs and benefits. Different technologies and deployment scenarios will likely yield very different results. To conduct such complex analysis, it is critical that the utilities engage with stakeholders to vet their modeling methodology and identify a set of reasonable scenarios and input assumptions to be assessed. Once developed, these models should evaluate and compare different scenarios against metrics that can be mapped to each of the benefit categories identified in statute.

The statute also requires the utilities to propose means of incenting deployment consistent with the findings of the analysis discussed above. These incentives will be particularly important given the role that private/consumer decision-making plays in the deployment of DERs. Unlike the highly centralized planning and procurement activities traditionally relied on by the IOUs, DERs involve individuals and business independently making decisions to invest in a particular resource and using that resource in a particular way. It will be critical to craft incentives that ensure that customers' rational self-interest aligns with the needs of the system, and recognizes the practical realities of how these technologies are offered in the marketplace. Additionally, creating opportunities for third-parties to leverage their customer portfolios to provide distribution services should be appropriately considered, recognizing that in many instances a third-party may be better situated than end-use customers to manage DER utilization. For example, third-parties are best positioned to pursue a utility contract to provide distribution and wholesale services that effectively allocates risk.

In addition to identifying the incentives or procurement models that can effectively motivate deployment and effective utilization of DER, there are undoubtedly barriers that may prevent any specific vision coming out of the utilities' analyses from coming to fruition. Identifying these barriers and thinking through ways in which these barriers can be removed is yet another element that must be included in these plans.

In many respects the objective of this initiative is to provide a roadmap that can be used to not only inform the types of investments and supportive programs the utilities should be pursuing, but also to identify changes that may be necessary to the regulatory, operational or legal environment that may impede efforts to maximize the benefits realized through the deployment DER. The plans should identify and describe key barriers, the venue for addressing that barrier, and, where reasonable, proposed solutions and timelines. Similarly, some of the barriers may be more technical in nature, having to do with the specific capabilities of legacy utility systems or new technologies. These considerations should also be identified to help the Commission and other stakeholders better understand the landscape and areas where additional R&D or demonstration efforts would be helpful. In addition to addressing barriers, each utility should identify any potential or existing conflicts of interest between the Commission's DRP objectives and the utility's shareholders. These conflicts of interest may exist in either the utility's development of its DRP or the execution and implementation of its DRP. To the extent a utility is able to recognize there are inherent conflicts of interest in this process, the Commission and other stakeholders should be aware so that these risks can be addressed appropriately in this proceeding.

3. What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

In principle, a methodology that calculates optimal locations of DERs should measure the value of locating DERs in an area given its ability to contribute towards meeting transmission and distribution system policy objectives including reliability, safety, resiliency, cost effectiveness, open and non-discriminatory access and customer choice goals.

SolarCity recognizes that the methodology for calculating optimal locations is a work in progress and will require stakeholder engagement to arrive at a common and fair methodology. AB 327 provides the opportunity to begin development of that methodology. As such, SolarCity emphasizes that full transparency of the methodology is as important as the identification of optimal locations themselves. Optimal locations alone, without disclosure of data and a fully repeatable methodology, limit the potential impact of AB 327 to encourage thoughtful DER integration.

However, any methodology that calculates optimal locations of DERs should translate into an incentive for customers to deploy DERs in high value areas, not as a basis to discriminate against customers living in areas with lower DER locational benefits. Protecting a customer's ability to install DER is critical to maintaining a customer's right to manage his or her personal energy portfolio. Consumer choice should not be constrained by centralized resource planning process, and a customer's ability to invest in DERs should not be constrained in anyway by a utility's distribution planning process.

Moreover, SolarCity believes the ability to meet customer choice should be formally considered in a utility's DRP by incorporating both avoided costs and measures of customer preferences in determining distribution infrastructure investment plans. While avoided costs are an important and familiar measure to integrated resource planners of locational value to the system, consumer demand for DER adoption in a given area represents a consumer preference that should be considered a cost if un-served through a utility's DRP. A relevant analogy would be that of a highway planner, who must balance the twin objectives of choosing a route to minimize cost while investing in infrastructure that takes people where they want to go. The highway route that results in the lowest capital outlay may not provide customers with the product desired. Similarly, a distribution network that is planned solely on avoided cost estimates may not deliver the infrastructure desired by its customers. In summary, SolarCity strongly believes utilities should consider both avoided costs and the ability to meet customer preferences when developing DRPs.

4. What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

Locational values should build upon the avoided cost metrics determined under the Net Energy Metering Successor tariff proceeding (R.14-07-002). These metrics should initially include, but not be limited to, the avoided cost of energy, ancillary services, greenhouse gas emissions permits, renewable energy credits, resource adequacy capacity, transmission and distribution level capacity, and electricity losses. More importantly, a new methodology that calculates optimal DER locations should reflect the full costs of meeting distribution level reliability needs, including services like reactive power for voltage support, and the system resiliency benefits associated with DER.

The incorporation of resiliency benefits is particularly important in this proceeding since these benefits were not counted in net benefit calculations for DERs to date. SolarCity believes any methodology to calculate optimal locations for DERs should consider the resiliency benefits of DER deployment in that area. A resource's ability to meet load in a given distribution area during a range of contingency events provides significant benefit to customers, which should be captured in any calculation regarding optimal locations. For a simplified example, customers of California's IOUs experienced an average of 162 minutes (2.7 hours) of unplanned service interruption annually over the last ten years according to CPUC data. Assuming an average residential customer demand of 1 kilowatt during these events and a value of lost load of $2,000 to $10,000 per MWh, the cost of these outages to customers would exceed $50-250 million per year. While the cost associated with this lack of resiliency in the distribution system is not currently captured in locational benefits, SolarCity believes a resource's ability to improve key utility reliability metrics like SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), CEMI (Customers Experiencing Multiple Interruptions) and CAIDI (Customer Average Interruption Duration Index) should be valued in calculating optimal locations of DERs.

Any incentives established to compensate DERs for being deployed in optimal locations should be customer-centric and distributed as simply and efficiently as possible to encourage customer participation. In the near term, compensation for DERs in optimal locations could be tariff-based and distributed as a combination of an initial upfront payment or rebate and monthly customer bill credits. An upfront payment for deployment would send a clear price signal to customers to invest in DERs in optimal locations, whereas a monthly bill credit could be tied to the longer term performance of the system.

Whether tariff-based or market-based, any compensation to incent deploying DERs in optimal locations should be guaranteed for long periods of time to provide investment certainty, similar to the long-term certainty provided to new conventional power plants authorized in the Long Term Procurement Plan (LTPP) or new distribution system investments authorized in the utilities' General Rate Cases. Furthermore, any compensation structure for optimally located DERs should complement rather than displace compensation frameworks like full retail Net Energy Metering (NEM), which have proven highly effective in driving deployment of DERs, like distributed solar, and are currently being evaluated under NEM Successor Tariff proceeding (R.14-07-002.)

In the longer term, SolarCity supports the development of transparent and publicly-developed methodologies that dynamically value DER at different locations on the distribution grid. Such a locational value would reflect both the distribution level and traditional transmission level avoided costs of a DER. This concept has recently been referred to as a distributed marginal cost (DMC) or distributed marginal price (DMP). While the wide spread use of DMPs or DMCs may not yet be practical for a variety of reasons, SolarCity supports the development of the initial methodologies in this proceeding and a stakeholder evaluation of the role these policies could have on DER deployment and the corresponding impact on reliability, resiliency, cost and customer choice. Overall, SolarCity embraces a longer-term vision of more granular and transparent distribution-level analysis that fully captures the benefits of DERs, some of which are not explicitly captured in locational values today.

5. What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

Small residential and commercial DER assets should be considered as load modification rather than generation in respect to distribution planning and network upgrade cost allocation. Small, behind-the-meter DER systems are an effective form of load modification. From a system planning study perspective, these smaller systems have less in common with large generators participating in the bulk power system than they do traditional load modification approaches. For example, small-scale, distributed generators look very similar to widespread energy efficiency programs that decrease overall load on a circuit. Therefore, utility distribution planning and cost allocation of network upgrades for these systems should be recovered in the same manner as costs incurred to meet changes in load.

Distribution planning: Currently, utility planning and investment to support DER penetration is reactive and occurs only in response to DER interconnection applications. Conversely, utility planning and investment to support load growth is proactive and is based on periodic load growth forecasts. In order to support customer choice in personal load management decisions, utilities should proactively plan for DER growth just as they plan for load growth. Since investments to accommodate load growth are rate-based by utilities, investments to accommodate DER growth that benefit all ratepayers should also be rate-based. To mitigate the risks in incorrectly forecasting DER growth, utilities can adapt existing distribution planning mechanisms to prevent over-building distribution systems for loads or DER growth that don't materialize. Without a proactive planning approach from utilities, DER growth will continue to be hamstrung by an infrastructure that does not aspire to keep up with its customers' desires to install DER.

Network upgrade cost allocation: System upgrades needed to accommodate small residential and commercial DER systems could be recovered in the same way as utility investments to serve load. Distribution system investments to serve these smaller customers are often shared across all customers on the circuit, rather than just the DER installation that triggers a network upgrade. Furthermore, as the design objectives of the distribution grid increasingly focus on "node-friendly" attributes, network upgrades required by DER installations will support the transition of the distribution grid into such a "node-friendly" network. As such, if benefits of these network upgrades are likely to be shared by all customers, then the accompanying costs should also be shared.

6. What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

In order to support the provision of distribution reliability services, IOUs will need the capability to adequately forecast and respond to distribution operational conditions. Since operational conditions are specific down to individual feeders, IOUs will need to assess their capability to plan for DER utilization by substation and feeder. Therefore, increased feeder modeling, forecasting capabilities and monitoring may be required.

That being said, increased utility capabilities in modeling, forecasting and monitoring do not necessarily require significant incremental expenditures solely for DER integration. First, much of the modeling and monitoring capability is needed for utilities as a normal function of its business. Second, much of the communications and IT infrastructure needed to support advanced monitoring is or will be in place via DER customers and third parties. For example, third-parties currently operate a significant DER communications network throughout California that could be leveraged by utilities to support their monitoring efforts.

7. What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

In addition to the locational benefits discussed in responses three and four, SolarCity believes there are potentially additional benefits to be gained by integrating DERs into the distribution system planning. Introducing greater transparency and fostering competition by integrating non-wires and third-party solutions into the distribution planning process will both drive down costs to meet forecasted distribution system needs and accelerate innovation among DER solutions to the benefit of customers.

8. What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

SolarCity recommends a small number of scenarios tied to assumptions and scenarios from the various California planning processes, including those managed by CAISO and CEC. While there are many scenarios that could be modeled, a fewer number of scenarios assessed well may provide more value in this initial DRP effort. SolarCity suggests the following initial planning scenarios:

- Base case/Trajectory: conservative expected case used in CPUC's Long-term Procurement Plan (LTPP) proceeding.
- High DER: high penetration of DER, spread evenly across all DER asset types. Utilize DER penetration of at least 20% of peak load by 2030.
- Expanded Preferred Resources: higher penetration of renewables, allocated across utility-scale, distribution and behind-the-meter assets

Furthermore, since distribution planning becomes increasingly difficult with longer time horizons, SolarCity suggests differentiating planning into the following time periods:

- 5-10 years: create feeder- and substation-specific plans
- 10+ years: create distribution planning area-specific plans, but not granular feeder or substation plans since likely accuracy is diminished greatly after 10 years

9. What types of data and level of data access should be considered as part of the DRP?

IOUs should make available the data used to perform their optimal location analyses. These analyses are based on historical data aggregated at feeders, substations and distribution planning areas, and do not utilize sensitive customer or operational data. Therefore, the IOUs should be transparent about the analyses performed and share the key operational data and assumptions at a granularity to match their analyses. For example, if the IOUs perform optimal location analyses by feeder, which requires DER growth, load growth, existing DER capacity, feeder min and max loading, and voltage regulation approach, this data should be shared by feeder so that the analysis can be replicated by third parties. Alternatively, if optimal location analyses reaches the complexity envisioned by Distribution Marginal Price/Cost analyses and vary by location along a distribution feeder, IOUs should share all the key assumptions used for those analyses as well as the DMP/DMC by feeder section using a tool easily digestible by third parties. In fact, the IOUs have such a tool in their existing Renewable Auction Mechanism maps, and these RAM maps should be leveraged to convey the key data and analysis results from the DRPs.

10. Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

Currently, AB 327 focuses on utilities identifying optimal locations for DER. A concern is that the IOUs could fulfill that narrow requirement by simply identifying distribution locations that they determine are optimal, without providing transparency into their methodology for identifying those locations. Furthermore, even if the IOUs are transparent in their approach, the analytical sophistication could be insufficient if not prescribed in advance. In order to make use of this valuable opportunity to evaluate the methodology for valuing DER, we propose that the IOUs perform a full locational value or distributed marginal cost/price analysis for a subset of their system.

While performing a full locational value or distributed marginal cost/price (DMP) analysis may be unwieldy for utilities to conduct on their full systems within the time constraints of the proceeding, the IOUs should have ample time to conduct such an analysis on a subset of their system (such as a distribution planning area and all the substations and feeders within that area). While there is no confirmed methodology for calculating such a locational value or distributed marginal cost/price, the process of performing that analysis within this OIR will dramatically accelerate progress towards a goal that is critical for integrating DER: accurate and granular locational value for DER. The value of the IOUs transparently performing this analysis is perhaps one of the largest potential benefits of this proceeding, as putting an accurate price on the value of DER to the grid is one of the most critical components for DER integration.

Furthermore, the IOUs should evaluate the locational value of DER against several typical utility distribution investments so as to highlight typical DER value in those defined use cases. Typical use cases include large capacity deferral (i.e. substation or feeder deferral), reliability enhancements (i.e. the reduction of outages frequency and/or duration), and typical network upgrades such as voltage regulation. These use cases should be included in the broad IOU analysis for optimal locations (assuming that the utility is planning at least one type of each investment in its territory) as well as the more detailed location value/DMP analysis.

11. What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

Recognizing that technologies, customer behavior, and systems requirements/needs evolve over time, it is important that the plans be viewed as living documents that are revisited on a periodic basis. Similar to other utility planning processes, SolarCity believes the Commission should require the plans to be revisited every 2-3 years and include both an independent evaluation/assessment of the utilities' success in implementing the plans as well as a refresh of the underlying analyses. Additionally, it may be useful to have more frequent meetings of a DRP working group, perhaps once a quarter to discuss the utilities' efforts to implement the plans. Such working groups can provide a relatively low resource means of ensuring the utilities are making progress against the plans and that any stumbling blocks or issues are identified and addressed in a timely manner.

12. What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

Ultimately the objective of this planning process is to ensure the utilities fully consider, in a robust manner, the opportunity to support and effectively utilize distributed energy resources to better serve end use customers in their respective service territories. Key criteria for assessing whether they have met this objective include:

- are the plans sufficiently comprehensive, in terms of whether they considered a reasonable and appropriate range of DER deployment scenarios and capabilities;
- have utilities addressed the required elements identified in the statute as articulated in section 769(b)(1)-(5);
- are the utility plans and methodologies are sufficiently transparent, both in terms of the access stakeholders are provided to the underlying methodologies as well as stakeholder opportunities to vet and provide feedback that informs the final plans; and,
- do utilities lay out or provide a path to actual implementation through a roadmap and timeline that establishes key milestones.

The last point is especially critical since this exercise will be a waste of valuable resources if the plans do not include information related to how the utilities intend, as a practical matter, to execute against the plans once developed and in what timeframe.

13. Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

Yes, DRPs should include this discussion of ownership evolution. Since the value of DERs will extend beyond energy output and into distribution reliability services, It is germane to identify an ownership model that enables customer and third-party ownership of such assets.

Utility insistence on ownership of reliability assets, such as substation transformers, is rooted in utility's historical expertise in operating such equipment, as well as confidence in availability. However, as DERs provide the same reliability services, such as substation upgrade deferrals, utilities are not the only parties with expertise. Furthermore, availability of DER to provide reliability services can be guaranteed through new, non-utility ownership structures. In fact, many third-party communication infrastructures are more robust and responsive than the aging utility communication infrastructures. Any lack of responsiveness in a single asset is mitigated by the small size of that asset (i.e. one residential DER system will have a negligible impact on system reliability if it does not respond, yet failure of a utility-scale reliability asset would have significant impact on the system).

Furthermore, where network upgrades are needed to accommodate MW-scale, wholesale DER assets, costs should continue to be allocated to the resource causing those costs to be incurred. However, if such a third-party asset owner pays the full cost of the required network upgrade, the third-party asset owner should be able to own the grid asset for which it pays through the network upgrade fee. Third-party payment for assets that another party owns[1] has few corollary examples outside the monopoly utility industry. In discussing the design philosophies for the grid of the future, this proceeding should also discuss the fair allocation of ownership rights for distribution assets that third-parties pay for. Beyond the fair allocation of ownership rights, third-party ownership of selected grid assets can provide valuable innovation in services to the utility industry. For example, if a third-party is required to pay for circuit monitoring equipment as a result of a network upgrade, that third-party should be allowed to utilize the circuit monitoring data to support innovative services, and to own the asset it paid for.

14. What specific concerns around safety should be addressed in the DRPs?

Safety is a foundational consideration that needs to be factored into the DRP process. That being said, SolarCity believes that a more distributed approach does not inherently pose any greater safety issues than the current more centralized approach and in fact may be superior in a number of respects. For example, in the wake of an emergency or force majeure event where the broader grid goes down, the ability for distributed resources to continue to operate, subject to appropriate anti-islanding

[1] See PG&E's Wholesale Distribution Access Tariff (WDAT), specifically, sections 13.4 and 23, for an example of current upgrade cost treatment.

protections, could be tremendously helpful in to maintain public safety, ensure critical services are maintained and facilitate clean up and recovery efforts. Safety is one of the factors against which different deployment scenarios should be compared based on a set of objective safety metrics. To the extent specific safety issues are identified, those issues should be run-to-ground given the fundamental importance of safety in all aspects of the energy system.

One area that we believe is closely related to safety is cyber security. As with safety more generally, we believe that a distributed approach can provide cyber security commensurate with if not superior to a centralized utility system. Decentralized, federated IT architectures have the potential to be less vulnerable to catastrophic cyber breaches because unauthorized access to the system may be more easily contained at the local, distributed level. To that end, cyber security should be factored into the overall framework and comparative analysis.

SolarCity notes that discussions related to safety should not be siloed within this proceeding. We recognize that other proceedings, for example the Commission's interconnection proceeding (R.11-09-011), provide a venue to address safety issues as they relate to interconnection. Similarly, issues related to safety and the interconnection of storage systems was thoroughly considered in the Commission's Distributed Generation Proceeding (R.12-11-005). Coordination with these proceeding will be important to prevent duplicative efforts and potential re-litigation of issues.

15. What, if any, further actions should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

SolarCity does not have any specific suggestions for further actions the Commission should consider at this time.

16. Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

SolarCity has reviewed the attached report and has no additional comments at this time. Overall we believe the report offers a comprehensive and highly effective framework for consideration of the complex issues involved. It is a useful guide to transform the energy system into one that both accommodates and takes full advantage of distributed energy resources.

III. CONCLUSION

We appreciate the Commission's consideration of our comments and look forward to future engagement in this proceeding.

Respectfully submitted,

________/s/_________

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